CR-118873

NASA CONTRACTOR SUMMARY REPORT

STUDY, COST, AND SYSTEM ANALYSIS OF LIQUID HYDROGEN PRODUCTION SUMMARY REPORT

by N. C. Hallett

FACILITY FORM 602

N71-73799 (ACCESSION NUMBER) (THRU)

62 (PAGES) None (CODE)

CR-118873 (NASA CR OR TMX OR AD NUMBER) (CATEGORY)

Distribution of this report is provided in the interest of information exchange. Responsibility for contents resides in the author or organization that prepared it.

NASA LIBRARY
AMES RESEARCH CENTER
MOFFETT FIELD, CALIF.

OCT 12 1982

NOT TO BE REMOVED
FROM LIBRARY
COPY NO. 1

Prepared under Contract No. NAS 2-3894 by
Air Products and Chemicals, Inc.
Allentown, Pennsylvania

for

MISSION ANALYSIS DIVISION
AMES RESEARCH CENTER
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

STUDY, COST, AND SYSTEM ANALYSIS OF LIQUID HYDROGEN PRODUCTION

by N. C. Hallett
Air Products and Chemicals, Inc.

ABSTRACT

This report contains information related to contemplated large-scale liquid hydrogen systems. Descriptions of feasible processes and equipment are presented. Information concerning availability and cost of required raw materials and energy are projected. Composite system analyses based on preliminary NASA hypersonic transport (HST) liquid hydrogen requirements indicate estimated average product cost of 7.7 to 8.8 cents per pound.

Preceding page blank

CONTENTS

	Page
ABSTRACT	iii
INTRODUCTION	1
ACKNOWLEDGMENT	1
Section 1	
STUDY DESCRIPTION	3
1.1 Hydrogen Market Demand	3
1.2 Large-Scale Liquid Hydrogen Systems	3
1.3 Study Program Description	4
Section 2	
CONCLUSIONS	7
2.1 Projected Production Costs	7
2.2 General Observations and Conclusions	7
Section 3	
PARAMETRIC STUDY	9
3.1 Hydrogen Gas Production and Purification	9
3.1.1 Steam Reforming	9
3.1.2 Partial Oxidation	10
3.1.3 Water Electrolysis	10
3.1.4 Coal Gasification	10
3.1.5 Hydrogen Halide	10
3.1.6 Process Requirements	10
3.2 Hydrogen Gas Liquefaction and Conversion	14
3.3 Storage of Liquid Hydrogen	14
3.3.1 Underground Storage	16
3.3.2 Above-Ground Storage	16
3.4 Distribution of Liquid Hydrogen	18
3.4.1 Truck Transport	18
3.4.2 Railroad Transport	18
3.4.3 Marine Transport	19
3.4.4 Pipeline Distribution	19
Section 4	
LOGISTICS	21
4.1 General Requirements	21
4.2 Specific Requirements for Liquid Hydrogen Production	21
4.2.1 Fossil Fuels	22

Preceding page blank

Page

4.2.2 Nuclear Power Raw Materials 22
4.2.3 Water 22
4.2.4 Oxygen 22
4.2.5 Refrigerants 22
4.3 Raw Materials Availability 26
4.3.1 Fossil Fuels 26
4.3.2 Nuclear Fuels 26
4.3.3 Water Power 26
4.4 Production, Trade, and Consumption 27
4.4.1 Solid Fuels 27
4.4.2 Oil 27
4.4.3 Natural Gas 27
4.4.4 General 27
4.5 Raw Material Costs 31
4.5.1 Coal, Oil, and Natural Gas 31
4.5.2 Water 31
4.5.3 Refrigerants and Oxygen 31
4.6 Projected Power Availability 31
4.7 Methods of Power Generation 36
4.8 Selection of Power Plant Size 36
4.9 Determination of Power Plant Investment 36
4.10 Determination of Power Cost 37
4.10.1 Load Factor 37
4.10.2 Plant Availability 37
4.10.3 Fixed-Charge Rate 37
4.10.4 Operating and Maintenance Costs 38
4.10.5 Cost of Fuel 38
4.10.6 Reserve 38

Section 5
COMPOSITE SYSTEM ANALYSES 41
5.1 Guideline Evaluations 41
5.2 Bangkok - 200 T/D 41
5.3 Honolulu - 200 T/D 42
5.4 Johannesburg - 200 T/D 43
5.5 Beirut - 300 T/D 44
5.6 Sao Paulo - 400 T/D 45
5.7 Sydney - 400 T/D 46
5.8 Tokyo - 500 T/D 47
5.9 Los Angeles - 1300 T/D 48

Page

5.10 Paris - 2000 T/D 49
5.11 New York - 2500 T/D 50

Section 6
SYNOPSIS 53
6.1 Data Accuracy 53
6.2 Future Production Costs 53
6.3 Future Technology 54

STUDY, COST, AND SYSTEM ANALYSIS OF LIQUID HYDROGEN PRODUCTION

by N. C. Hallett
Air Products and Chemicals, Inc.

INTRODUCTION

Air Products and Chemicals, Inc. was retained by the National Aeronautics and Space Administration (NASA) to perform a study related to systems that produce liquid hydrogen as propulsion fuel in aircraft. The study objective was that of developing information to project hydrogen fuel costs in the post-1980 period. These costs were to reflect production and distribution technology, plus costs of raw materials and process energy. Further, consideration of integrating hydrogen fuel production with other industrial activities was to be considered. NASA proposed a hydrogen fuel requirement schedule based on preliminary projections for hypersonic transport (HST) systems in the post-1980 period.

The Final Report* for this program contains the elements and conclusions of the study. This Summary Report incorporates certain salient features drawn from the more complete Final Report.

ACKNOWLEDGMENT

This study program was conducted by Air Products and Chemicals, Inc., Project 01-6-1535, under NASA Contract Number NAS 2-3894 for the National Aeronautics and Space Administration, Ames Research Center, Moffett Field, California. Acknowledgment of key personnel involved with this study is made in the listing below:

National Aeronautics and Space Administration Personnel:

J. C. Delaney, Contracting Officer
C. Smith, Technical Monitor
D. Wilcox, Technical Monitor

Air Products and Chemicals, Inc. Personnel:

G. E. Eissmann, Publication Manager
J. B. Gibbs, Research Engineer
H. C. Totten, Project Manager
C. E. Hepler, Jr., Design Specialist
F. Himmelberger, Special Project Engineer
G. E. Kinard, Process Engineer
D. D. McCarthy, Cost Engineer
G. R. Oemke, Machinery Engineer
S. S. Paterno, Specialty Design Manager
A. H. Singleton, Research Manager
P. A. Sipple, Cost Engineer
W. A. Snow, Manager, Advanced Products Department
V. Webster, Project Secretary

* NASA CR73,226

Section 1

STUDY DESCRIPTION

Introductory remarks concerning the study are presented in the following paragraphs. Section 2 is a presentation of observations and conclusions drawn from the study. Subsequent sections incorporate information leading to cited observations and conclusions.

1.1 HYDROGEN MARKET DEMAND

Gaseous and liquid hydrogen have been marketable commodities for less than two decades. Demand for hydrogen prior to 1955 was small compared with present standards. These small requirements were satisfied generally by small-scale generation equipment.

Since 1955, however, major developments in two specific areas have resulted in a substantial demand for hydrogen. Development of rocket propulsion by burning liquid hydrogen has resulted in the present demand for liquid hydrogen. Secondly, developments within the process industry in general have established substantial demands for gaseous hydrogen. Agricultural chemical production, for example, utilizes gaseous hydrogen as a basic synthesis component.

Current world production of liquid hydrogen is estimated to be between 200 and 400 tons per day, with most of the liquid being used in rocket propulsion. By comparison, aggregate production requirements for a proposed hypersonic transport system approaches 8000 tons per day. Individual proposed area requirements vary between 200 and 2500 tons per day per facility.

Therefore, this report is directed at satisfying the liquid hydrogen requirement of the proposed HST system. Other liquid hydrogen requirements will exist but probably will be incrementally small when compared to possible HST needs.

1.2 LARGE-SCALE LIQUID HYDROGEN SYSTEMS

Basic questions of raw material supply and process energy source must be considered for the large-scale facilities. Raw material sources for hydrogen can be classified as aqueous solutions or hydrocarbon materials. To date, natural gas and petroleum products have been primary raw materials used for product hydrogen. Raw material for hydrogen production in the quantities studied in this project would be equivalent to approximately 10 percent of the world's annual natural gas production. Reserves of natural gas and petroleum products would deplete at accelerated rates with the undertaking of this HST system. To alleviate the raw material problem, aqueous solution processing (water electrolysis for example) may be a hydrogen generation process. Also, carbonaceous materials, namely, coal in coal-water processes, will be developed for use. In any event, the supply of required amounts of raw material will be a major problem for large-scale hydrogen production.

Process energy, likewise, will be required at high rates compared to current process industry standards. Electrical energy will be needed in vast amounts for electrolysis systems, for example. It is projected

Preceding page blank

that the product hydrogen for the proposed HST system would require as much as 8 percent of all electrical energy now produced in the United States.

In addition to the raw material and process energy problems, there will be radically new applications of technology. The largest currently operating liquid hydrogen production facility has a production rate of approximately 50 tons per day. By comparison, proposed production requirements for the HST system will range from 200 to 2500 tons per day. The required scale-up and extension of technology is apparent.

1.3 STUDY PROGRAM DESCRIPTION

In accordance with the stated objectives, the study program was organized into three specific task activities:

Section 3, Parametric Study
Section 4, Logistics
Section 5, Composite System Analyses

The parametric study incorporates extensive detail description of anticipated liquid hydrogen systems. Information was developed with respect to the following four specific operations in a liquid hydrogen system:

(1) Hydrogen gas production and purification

(2) Hydrogen gas liquefaction and conversion

(3) Storage and transfer of liquid hydrogen

(4) Distribution of liquid hydrogen

For each of the four basic operations or subsystems, several techniques, equipment types, or operating modes are possible. The basic objective of the parametric study, then, was to develop "parametric information" for each of the four subsystems. After development of the parametric or "building block" data, liquid hydrogen systems could be constructed in accord with postulated geographic liquid hydrogen requirements.

Data and information developed in the parametric study can be termed "descriptive". That is, information related to process and equipment description was required. Based on the descriptive information, unit requirements, or other characteristics of the respective subsystems, were quantitatively developed. Amounts of raw material, process energy, capital investment, etc., required for unit production from the given subsystem alternates were developed. Cost of the required commodities was not developed. Estimates of the required quantities of respective commodities were generated. Capital investment, for example, was based on Washington, D.C., costs and 1967 United States dollars. In addition, the unit requirements were developed so that the effect of plant size could be reflected.

The descriptive and quantitative information developed is contained in section 3. From the information developed, it is possible to determine the liquid hydrogen facility requirements as dependent upon chosen "building blocks" and plant production requirements. This information provides the basis for making comparisons between various systems conceived for the same production requirements.

The logistics activity was primarily the development of projected availability and costs of commodities required in liquid hydrogen production. Data was assembled in relation to types and amounts of commodities for various systems at respective georgraphic locations. Generation of information detailing prospective electrical energy systems was another major part of the logistics activity. Study of current and projected electrical energy supply and demand patterns was completed with detailed analysis concerning liquid hydrogen plant locations. The data developed in the logistics work is described in section 4.

Composite system analyses, the third major portion of the study program, incorporated extensive numerical analysis of the parametric and logistic information. The analyses were based upon a possible fuel-requirement schedule for HST service. This schedule is presented in table 1-1.

TABLE 1-1. HST FUEL SCHEDULE

Location	Nominal Daily Requirement T/D LH_2
Bangkok, Thailand	200
Honolulu, Hawaii, U.S.A.	200
Johannesburg, Union of South Africa	200
Beirut, Lebanon	300
Sao Paulo, Brazil	400
Sydney, Australia	400
Tokyo, Japan	500
Los Angeles, California, U.S.A.	1300
Paris, France	2000
New York City, New York, U.S.A.	2500

Various liquid hydrogen plants were "built up" from the parametric study information. Based on the types and amounts of commodities required for respective plants, comparative sets of production costs were drawn. From this, the projected unit production cost of liquid hydrogen fuel was developed at the respective locations.

A second set of unit production costs was developed to reflect effects of combining liquid hydrogen production with other industrial activities in the respective areas. This incorporated preliminary projection of the general industrial patterns to be expected in specific areas. Based on this information, reductions in production cost were projected for certain of the areas considered.

Detailed information and calculational results of the composite analyses are presented as section 5 of the Contractor Report.

A final activity within the study program was that of defining areas where advancement may reduce the production cost of liquid hydrogen. Information and results of this activity are presented as section 6 of the Contractor Report.

Section 2

CONCLUSIONS

The results of production cost estimates are shown in table 2-1. Calculation results are presented in section 5 of this report.

2.1 PROJECTED PRODUCTION COSTS

The results of production-cost estimates are shown in table 2-1. Calculation results are presented in section 5 of this report.

TABLE 2-1. PROJECTED PRODUCT COSTS

Plant Location	Nominal Production Rate (Tons LH_2/Day)	Stand Alone Facility Product Cost[a] ($/lb LH_2)	Integrated Facility Product Cost[a] ($/lb LH_2)
Bangkok, Thailand	200	0.113	0.093
Honolulu, Hawaii	200	0.132	0.124
Johannesburg, Union of South Africa	200	0.108	0.100
Beirut, Lebanon	300	0.106	0.087
Sao Paulo, Brazil	400	0.104	0.095
Sydney, Australia	400	0.098	0.083
Tokyo, Japan	500	0.099	0.084
Los Angeles, California	1300	0.081	0.071
Paris, France	2000	0.085	0.077
New York City, New York	2500	0.079	0.073
Total Weighted Average Cost	8000	0.088	0.079

[a]Byproduct credit incorporated where applicable.

2.2 GENERAL OBSERVATIONS AND CONCLUSIONS

Contemplated liquid hydrogen systems will be characterized by their respective gaseous hydrogen generation and purification process. Hydrocarbon processing will be employed in most situations. Projected economics and raw material availability favor the steam reforming or partial oxidation type processes. Electrolysis processes, although not presently projected as being economically attractive, will likely become somewhat more competitive in the future. Advances in process technology and materials of construction will be more beneficial to the electrolysis processes than to the hydrocarbon processes. Other process types could be further considered for large-scale systems. For example,

Preceding page blank

hydrogen halide systems, presently undesirable because of poor economics, could prove worthy of consideration as technology changes.

In view of current concern regarding urban environments, hydrocarbon processing may not be desirable in larger, well-developed communities. In those cases, electrolysis processing could be a feasible process, but with approximately 30 percent additional product costs. In view of this, it is suggested that effort be expended in the near future to more fully develop the electrolysis process technology in order to reduce costs for this process in line with competing processes.

The analysis technique developed in this report can be utilized in future evaluations. Incorporation of updated numerical data will yield different results, but the evaluation technique will be valid. For example an 11 percent annual capital charge rate was used for this report. Government participation in financing could affect a different capital charge rate (6 percent, for example), which would result in a changed set of calculations based on this analysis technique.

Location of the production facilities affects liquid hydrogen production costs. New sets of calculations could be developed for alternate liquid hydrogen use-points. It is expected that significant cost reductions could result from such an analysis.

Integrated facilities, as herein discussed, should result in projected production cost savings of 10 to 20 percent of the stand-alone operations. The cost savings are based on current experience with other intergrated facilities. Upon achieving clearer understanding of the projected hydrogen program, a more detailed evaluation of the integrated facility could be made for specific locations. It is projected, however, that detailed integrated-facility studies would show production cost savings ranging from 10 to 30 percent of the stand-alone costs.

Section 3

PARAMETRIC STUDY

The major objective of the parametric study was to establish commodity unit quantities required for production by large-scale liquid hydrogen systems. These unit quantities were developed as a function of system size. Another objective of the parametric study was to provide a technical description of various components which, when combined, constitute the total hydrogen supply system. Detailed information developed, based on these objectives, has been presented in section 3 of the Contractor Report. Certain summary information drawn from the formal report is presented in paragraphs below. Organization of the summary information follows the subsystem breakdown of the Contractor Report.

3.1 HYDROGEN GAS PRODUCTION AND PURIFICATION

The hydrogen gas production and purification subsystem, frequently termed "gas plant", supplies the liquefaction subsystem with gaseous hydrogen of suitable purity. Types of gas plants are based upon various raw materials from which gaseous hydrogen can be produced. The raw materials that can be used are classified as hydrocarbons, carbonaceous fuel, or aqueous solutions. From these raw materials, hydrogen gas is generated in a combustion or reformer reaction, or in the dissociation of water or an aqueous solution.

Several processes, or variation of processes, are possible with the above-mentioned raw material types. After preliminary consideration, five gas plant systems were selected for consideration in the parametric study. These systems are known as:

(1) Steam reforming

(2) Partial oxidation

(3) Water electrolysis

(4) Coal gasification

(5) Hydrogen halide

3.1.1 STEAM REFORMING

Steam reforming historically has been a basic process employed in hydrogen generation where natural gas is readily available as a feed stock. Generally, the process incorporates reaction of steam and natural gas feed stock into products of hydrogen and carbon-oxides. Suitable processing isolates the hydrogen from other components and makes it available as supply material for the liquefaction system.

3.1.2 PARTIAL OXIDATION

Partial oxidation is second only to and is similar to steam reforming in that both processes use a variety of hydrocarbon materials as the raw material supply. Partial oxidation, however, also incorporates oxygen as a raw material. Oxygen supports a partial combustion of the hydrocarbon raw material. Proper control, with additional steam, results in gaseous hydrogen and carbon-oxides being generated as reaction products. Whereas steam reforming processes normally have been designed for natural gas or methane gas feedstock, partial oxidation processing normally incorporates oils or heavy hydrocarbon petroleum products as raw materials.

3.1.3 WATER ELECTROLYSIS

Generation of hydrogen by water electrolysis is based upon electrochemical dissociation of water into elemental hydrogen and oxygen. Hydrogen generation by this process has been a laboratory activity for many years and, in recent years, has formed the basis for fuel cell experimentation. Small commercial installations are in operation for production of hydrogen. Commodity amounts by this process have not been accomplished to date, but sufficient understanding and study have been undertaken and achieved to project the process as being feasible for large-scale hydrogen supply systems.

3.1.4 COAL GASIFICATION

Gasification of coal is a process that incorporates reactions similar to those of the partial oxidation process. That is, partial combustion and reforming reactions result in gaseous hydrogen and carbon-oxide products. The basic difference between this process and other combustion-reforming processes is that of raw material. The prime source of hydrogen in the coal gasification process is in the water and not in the coal or fuel material. Coal gasification processes are commercially the oldest for large volume production of water gas ($CO + H_2$). Indications are that this process could become one of the more important hydrogen sources.

3.1.5 HYDROGEN HALIDE

Electrolysis of water as a hydrogen generation process can be modified to incorporate an aqueous solution of salts or acids. In particular, proposed processing of hydrogen-halide solutions, as opposed to water electrolysis, should result in a significant reduction in electrical energy requirements. This process is currently in developmental stages. Future work may be done to establish the process as a feasible system for commodity scale operation.

3.1.6 PROCESS REQUIREMENTS

Although the processes are different, it was possible to consider them in a parametric fashion. That is, the unit requirements for the various processes were generalized so that comparison and dependency upon system size could be understood. The requirements were generalized into the following categories:

(1) Process Elements

(a) Raw material

(b) Process energy

(c) By-products

(2) Cost Elements

(a) Capital investment

(b) Operating cost

With these categorizations, it was possible to detail commodity requirements for each process with respect to system size.

Detail development of the mathematical information related to the processes is presented in the Final Report. Summary information and nomenclature is presented in table 3-1 at the end of this report section. It should be noted that by-product requirements were developed to provide a possible means for determining by-product revenues.

Information was organized for analysis in the form of algebraic expressions. Process elements are generalized in a linear equation:

$X = K + MC$, where

X = unit requirement

K = constant

M = scale factor

C = nominal gaseous hydrogen production capacity in tons/day (T/D) (1)

Cost element information is generalized in an exponential equation:

$$X = I\left(\frac{C}{250\ T/D}\right)^{M}, \text{ where}$$

X = investment or cost

I = base investment or cost

C = nominal gaseous hydrogen production capacity in T/D

M = exponential scale factor (2)

TABLE 3-1. GAS PRODUCTION AND PURIFICATION PARAMETRIC DATA

Process Elements

X = K + MC, where
X = unit requirement
K = constant
M = scale factor
C = nominal gaseous hydrogen capacity in T/D

X = K*, where
X = unit requirement
K* = constant

Items	Steam Reforming			Partial Oxidation			Electrolysis	Coal Gasification Lignite	Coal Gasification Bituminous	Hydrogen Halide
	K lb /lb GH_2	M lb/lb GH_2 T/D	K* lb/lb GH_2	K lb/lb GH_2	M lb/lb GH_2 T/D	K* lb/lb GH_2	K* lb /lb GH_2	K* lb/lb GH_2	K* lb/lb GH_2	K* lb /lb GH_2
Raw Materials										
Feed			1.90 (CH_4)			3.89 (Bunker C)	9.0 (H_2O)	8.84	20.3 (H_2O)	9.0 (H_2O)
Fuel	1.44 (CH_4)	-4.4 x 10^5 (CH_4)		0.40 (Bunker C)	-3.1 x 10^5 (Bunker C)	8.84		12.10 (Coal)	8.74 (Coal)	1.1 (CH_4)
Cooling Water Makeup			22.4			12.5	11.5	23.5	26.0	13.0
Boiler Water Makeup			16.6			12.5	0	0		0
Other			0			0	0	5.20 (O_2)	5.20 (O_2)	0
Byproducts			5.3 (CO_2)			6.0 (CO_2) 5.0 (Steam) 0.11 (C)	7.92 (O_2)	24.0 (CO_2)	24.0 (CO_2)	7.92 (O_2)
			K* kwh/lb GH_2			K* kwh/lb GH_2	K* kwh/lb GH_2	K* kwh/lb GH_2	K* kwh/lb GH_2	K* kwh/lb GH_2
Process Energy			0.47			1.3	21.5 (Hi pressure, Hi temp.) 21.6 (Lo pressure, Hi temp.)	0.57	0.57	15.3

TABLE 3-1. GAS PRODUCTION AND PURIFICATION PARAMETRIC DATA (Concluded)

Cost Elements

$$X = I\left[\frac{C}{250\ T/D}\right]^{M}, \text{ where}$$

X = investment or cost

I = base investment or cost

C = nominal gaseous hydrogen production capacity in T/D

M = exponential scale factor

Item	Steam Reforming		Partial Oxidation		Electrolysis		Coal Gasification Lignite		Coal Gasification Bituminous		Hydrogen Halide	
	I $	M	I $	M	I $	M	I $	M	I $	M	I $	M
Capital Investment	7.65 x 10^6	0.7	8.46 x 10^6	0.7	36.3 x 10^6 (Hi press. Hi temp.) 28.5 x 10^6 (Lo press. Hi temp.)	0.89 (Hi press. Hi temp.) 0.88 (Lo press. Hi temp.)	16.9 x 10^6	0.7	20.8 x 10^6	0.7	46.5 x 10^6	0.9
Operating Cost	I $/yr 1.28 x 10^6	M 0.73	I $/yr 1.46 x 10^6	M 0.73	I $/yr 2.62 x 10^6	M 0.73	I $/yr 2.57 x 10^6	M 0.65	I $/yr 2.89 x 10^6	M 0.65	I $/yr 4.35 x 10^6	M 0.76

3.2 HYDROGEN GAS LIQUEFACTION AND CONVERSION

Having considered systems associated with production and purification of hydrogen gas, attention is directed to liquefaction and conversion of the gas into the required liquid hydrogen product. This part of the over-all liquid hydrogen system generally is termed the liquefaction process or liquid plant. The liquid plant process can be visualized as a three-step heat removal process, that is:

(1) Refrigerating gaseous hydrogen from the as-received temperatures to its boiling point (-423°F at atmospheric pressure, for example)

(2) Removing latent heat of vaporization as gaseous hydrogen condenses to liquid hydrogen

(3) Removing latent heat of conversion as the ortho-para concentration proceeds towards equilibrium at the liquid temperature

To accomplish the above-noted heat removal, several refrigeration schemes are possible. In fact, in each instance where it has been necessary to develop such a system, a different process has been employed. However, for purposes of this study, certain guidelines were established to permit development of comparative analyses.

A major guideline was that of evaluating process schemes on the basis of required process energy. That is, it was desirable to select that process which would require the least amount of energy for operation. Further, it was specified that the product conversion level would be 95 percent para, 5 percent ortho. To provide for long-term storage, the 95 percent para conversion level is reasonable, and would provide for the most general use of the product.

Upon evaluation, it was determined that the liquefaction and conversion process would incorporate a high-level refrigeration system (ambient temperature to -320°F) and a low-level refrigeration system (-320°F to -423°F). The high-level system can be described as a modified "cascade" refrigeration system incorporating several smaller, heat-interchanging refrigeration circuits with a variety of working fluids. Low-level refrigeration was taken as a 1500 psig hydrogen fluid refrigeration system functioning much the same as a household refrigerator.

The choice of these systems was dependent upon the projection of future heavy machinery technology. After establishing detail projections for equipment capabilities, the systems requiring the least process energy for the 95 percent para product were chosen.

After developing the descriptive process information, evaluation of commodity requirements was made. The data was organized in a manner similar to table 3-1, and is presented in table 3-2.

3.3 STORAGE OF LIQUID HYDROGEN

Storage of liquid hydrogen is an important facet of the complete liquid hydrogen supply system. It becomes necessary to balance storage equipment capital investment and product loss with respect to other overall facility considerations. For example, less costly storage systems and attendant

TABLE 3-2. GAS LIQUEFACTION AND CONVERSION PARAMETRIC DATA

Process Elements

$X = K^*$, where X = unit requirement K^* = constant

Item		K* lb/lb LH_2
Raw Materials		
Feed Gas	GH_2	1.04
Refrigerants	N_2	0.04
	CH_4	0.01
	C_3H_8	0.02
	C_2H_4	0.02
		K* kwh/lb LH_2
Process Energy		4.46

Cost Elements

$$X = I \left[\frac{C}{250\ T/D} \right]^M$$, where

I = base investment or cost

C = nominal gaseous hydrogen production capacity in T/D

X = investment or cost

M = exponential scale factor

Item	I $	M
Capital Investment	31.5×10^6	0.8
	I $/Yr	M
Operating Cost	1.91×10^6	0.65

moderate loss of product may necessitate oversize gas and liquid plants to cover the product loss. With this in mind, an extensive review of hydrogen storage technology was completed. Liquid hydrogen storage was considered in two categories:

(1) Underground storage

(2) Above-ground storage

3.3.1 UNDERGROUND STORAGE

Although underground storage of liquid hydrogen has not been attempted to date, this method is of interest in that storage could conceivably be accomplished so that overhead land surface would be available for other uses. There has been significant activity in developing underground storage of liquid methane, and a number of large-scale underground liquefied methane storage systems are in operation.

Noting the above, extensive review of underground storage information was completed, and it was observed that underground storage of liquid hydrogen did not appear feasible. Major mechanical problems and projected high product losses seem to pose restraints at this point. It was concluded that underground storage would not be projected for large-scale liquid hydrogen systems. However, a continuing effort in this area is expected in an attempt to solve present problems.

3.3.2 ABOVE-GROUND STORAGE

Above-ground storage of liquid hydrogen has been satisfactorily accomplished for several years. Various types of above-ground storage equipment are feasible for liquid hydrogen service. These systems differ from each other in their respective means of insulating the liquid hydrogen from ambient surroundings. Differences in insulation techniques result in variation in capital cost and product loss characteristics. After development of detail information about the various above-ground systems, it was observed that one type offered the desirable characteristics for liquid hydrogen systems. This system is generally known as double-wall tank, evacuated powder insulation.

The double-wall tank, evacuated powder insulation system exhibits high capital cost and low product loss characteristics. It is judged that the high capital cost of the storage equipment is offset by capital cost saved in other facility production equipment due to lower "over-production" requirements. The "over-production" requirements are reduced for this storage system by the efficient insulation scheme.

All data developed for liquid hydrogen storage is presented in section 3 of the Contractor Report. Some information pertaining to the double-wall tank evacuated powder insulation system is presented in table 3-3.

TABLE 3-3. DOUBLE WALL, EVACUATED PERLITE STORAGE TANK DATA

Nominal Tank Capacity	Heat Leak	Equivalent Product Loss Due to Heat Leak	Capital Investment
lb LH_2	Btu/Hr	% Capacity/Day	$
6×10^5	1.6×10^3	0.034	0.74×10^6
18×10^5	3.2×10^3	0.023	1.98×10^6
36×10^5	5.1×10^3	0.018	3.75×10^6
72×10^5	8.2×10^3	0.015	7.20×10^6

3.4 DISTRIBUTION OF LIQUID HYDROGEN

Some means will be required for distributing liquid hydrogen from production or storage to the use-point. In simplest form, this may mean transfer of fluid from a storage tank into a using vehicle a short distance away. However, it may be desirable to have the liquid hydrogen production point well removed from the use-point, with a long-distance distribution system required.

This portion of the parametric study, then, was directed towards schemes that could be employed in various ways. To provide the information, the distribution schemes were characterized by the basic equipment to be utilized. The schemes considered were:

(1) Truck transport

(2) Railroad transport

(3) Marine transport

(4) Pipeline distribution

3.4.1 TRUCK TRANSPORT

Truck transport is used currently as the major distribution scheme. Truck transportation provides a flexible system for distribution from a small number of production points to a large number of use-points. By contrast, large-scale hydrogen systems may require distribution primarily from a single production point to a single use-point. For this, it is conceivable that a special fleet of truck transports would ply a single distribution routing between the production point and use-point.

The basic equipment employed in such a truck transport system would be a semi-trailer type vehicle. This semi-trailer vehicle would be an insulated tank mounted on standard semi-trailer bogies. Capacities of these vehicles are projected to 10,000 pounds of liquid hydrogen. It is noted that several units would be involved in the movement of any substantial amount of liquid hydrogen. The complex scheduling and large numbers of units required to service large-scale systems is an inherent problem with this distribution system.

Product losses associated with the 10,000-pound units can be summarized in two categories, annual steady state losses and operational losses. Annual losses, those based on regular utilization of the unit, are projected to be 21,150 pounds annually per unit. Operational losses, those associated with loading of the unit, are projected to be 550 pounds per loading. Capital investment and operating costs are projected to be $150,000 per unit and $0.50 per vehicular mile, respectively.

3.4.2 RAILROAD TRANSPORT

Railroad transport is similar essentially to truck transport. Capacity of future rail units is projected to be 25,000 pounds of liquid hydrogen. The unit train concept (a train of liquid hydrogen railcars) could be employed over special trackage between production and use-points. However, complexity of scheduling and large numbers of units again would be characteristic of railroad transport systems

that would service large-scale hydrogen systems. Product losses can be summarized as steady state losses of 52,875 pounds annually per unit, with operational losses of 2375 pounds per loading of the unit. Capital investment is projected to be $250,000 per unit. Operating costs, primarily tariff costs, are projected to range between $1.25 and $0.50 per mile, corresponding linearly to vehicular mileage distances ranging from 50 to 1000 miles. Also projected is an estimated $0.06 per vehicular mile maintenance cost.

3.4.3 MARINE TRANSPORT

Marine transport can be considered in two major modes:

(1) Regional (local) distribution

(2) Long-distance distribution

Regional distribution by marine transport has been employed in recent years for certain liquid hydrogen operations. This distribution method is based upon use of liquid hydrogen storage tanks mounted on modified ship (barge) hulls. The barges are towed between production and use-points within the distribution network. The main disadvantage of this regional marine distribution system is that of relatively slow distribution rates and attendant limitations upon routing. It is not projected that regional marine transport will be employed in large-scale liquid hydrogen systems.

Long-distance distribution of liquid hydrogen by marine transport has not yet been accomplished. However, long-distance marine transport of other cryogenic fluids is currently in operation. Liquefied natural gas distribution , for example, is in effect along several transoceanic routes at the present time or will be in the near future. It is reasonable to project that large-scale oceanic distribution of liquid hydrogen could be undertaken.

Huge tankers have been postulated for oil transport. These "super barges" would be self-propelled vessels, each with a capacity of 500,000 tons of oil. It is judged that vessels of similar size could be in service for liquid hydrogen operations. A capacity of 25,000 tons of liquid hydrogen could be expected. Loss characteristics of such ships might be on the order of 0.04 percent per day, or 10 tons per day for the 25,000-ton unit. Based on recent data for liquefied natural gas vessels, a capital investment of $46,000,000 might be expected. Operating costs per marine transport were not developed in the study. Such an evaluation could be done when more specific information about marine transport is available.

3.4.4 PIPELINE DISTRIBUTION

Pipeline distribution probably will be the major distribution system in large-scale liquid hydrogen systems. Specifically, systems with close proximity of production and use-points are particularly applicable for the pipeline distribution scheme. Because of its importance, extensive detail study was devoted to pipeline distribution in the course of this program. Several types of systems were considered. The observation is made that pipeline systems likely will be of the double-wall, multi-layered insulation type currently in use today. No specific technological requirements will be necessary for this system other than mechanical developments leading to lower fabrication cost.

Pipeline is seen as a possible cross-country distribution device for moderate distances. The tendency for the fluid to evaporate due to pressure drop and system heat leak poses restraints upon system capability. It may be necessary, for example, to install reliquefaction stations along a cross-country pipeline. The complex operating economics of such a system are apparent.

As noted, the pipeline distribution system is applicable particularly to local distribution. For example, a set of data was developed for a hypothetical local pipeline distribution system. The system characteristics were taken as:

(1) Mass flow - multiples of 120 tons per hour (T/hr) (consistent with one aircraft fueling per hour or multiples thereof)

(2) Distance - 2 miles (distance is storage to aircraft servicing manifold)

(3) Pressure drop - maximum of 5 psid

(4) Exit pressure - saturated at approximately 3.0 psig

Under these conditions, product losses of 7 percent of inlet flow are projected. Line sizes (internal pipe of double-wall system) of 18 and 24 inches were satisfactory respectively for 120 T/hr and 240 T/hr of flow.

Operating costs for such a pipeline system are minimal and are normally incorporated with operating costs within the facility. Capital investment is projected to be dependent upon inner-line size. A value of $15 per foot per inch of diameter is seen as representative of the capital cost of such a system.

Section 4

LOGISTICS

This section summarizes commodity requirements, cites their availability, and estimates their contribution to the post-1980 liquid hydrogen cost.

4.1 GENERAL REQUIREMENTS

The plant cycles described in section 3 identify the need for the raw materials and power essential for liquid hydrogen production. Potentially suitable commodities, if available in large quantities at a competitively favorable cost, include coal, petroleum, natural gas, electricity, and water. From a general competitive standpoint, these commodities are in world-wide demand. The growth of population, coupled with comparable increases in per capita consumption of energy, has taxed the world's ability to supply sufficient quantities of fuel or electric power.

With this background of competition for energy sources, which will be manifested on world-wide and local levels, raw materials and power to produce liquid hydrogen must be procured. Where fossil fuel costs may be excessive, largely due to bulk transport expenses, nuclear energy may provide a less costly avenue to power production.

4.2 SPECIFIC REQUIREMENTS FOR LIQUID HYDROGEN PRODUCTION

Raw materials required for the production of liquid hydrogen can be assigned to four categories:

(1) Fossil fuels: which can be used as feed stock, fuel or for production of power

(2) Nuclear power raw materials: such as uranium, thorium, and heavy water used for generation of electricity

(3) Water: used as process water for cooling or as a source of steam. Demineralization of this water for use in electrolytic cells is included in investment and operating costs associated with that process.

(4) Other raw materials required in lesser quantities: notably, nitrogen, oxygen and refrigerants

Of these, only the fossil fuels present a basic logistics problem; i.e., the movement of large quantities of material to the hydrogen plant site. The transmission of electricity generated at the mine mouth or at a hydroelectric site to the use-point by high voltage transmission lines will also pose logistic problems at several locations.

4.2.1 FOSSIL FUELS

As a result of analyzing the raw material and power requirements for the processes described in section 3, table 4-1 has been prepared to show annual fossil fuel requirements for each proposed hydrogen plant location. The "Total (Maximum)" column in the table applies if electrolysis is considered economically feasible or necessary. Since section 5 shows, however, that electrolysis, based on current assessments, will not be economically competitive, the "Total (Probable)" column in the table defines the maximum requirement if either of the cost-competitive processes are selected. These include steam reforming of natural gas and partial oxidation at all locations and gasification of coal at the Johannesburg and Sydney sites. Presently, it appears that oil would be used as fuel in the steam-reforming process. This is dictated solely by the relatively high cost of gas at all tentative hydrogen plant locations. Actually, non-fossil fuel power generation is desirable in most instances as shown in table 4-1.

4.2.2 NUCLEAR POWER RAW MATERIALS

In this report, uranium, thorium, or heavy water requirements for the nuclear power plants are considered part of initial investment or as replacement materials in the cost of operation rather than as raw materials. This is deemed the most convenient method for there is presently no substantial trade in these commodities. The quantities required do not fall into the category of bulk transport, and delivery to the use-point would be in a purified and modified form, such as fuel elements, which more closely resemble manufactured products than raw materials.

4.2.3 WATER

Although water requirements for process, cooling, and generation of steam are high, it is unlikely that water will impose a logistics problem. It undoubtedly will be acquired locally. Therefore, water will be a factor in hydrogen plant location rather than in logistics. (Water costs are considered in paragraph 4.5.2.)

4.2.4 OXYGEN

Aside from the major raw material requirement for hydrogen gas generation, the partial oxidation and coal gasification processes analyzed for the study require oxygen. In the case of partial oxidation, it has been more convenient to include the cost of the oxygen (air separation) plant as part of the overall hydrogen facility. Hence, the cost of oxygen is included as part of the capital investment and operating costs. In the case of coal gasification, process cost analysis was simplified by treating oxygen as a raw material. The tonnages required for coal gasification are indicated in table 3-1.

4.2.5 REFRIGERANTS

The liquefaction process for all locations embodies a cascade refrigeration cycle requiring nitrogen, methane, propane, and ethylene. The quantities required are shown in table 3-2. Since an air separation plant has been provided for the partial oxidation process, nitrogen would already be available for the liquefier associated with that process.

TABLE 4-1. ANNUAL RAW MATERIAL REQUIREMENTS FOR LIQUID HYDROGEN PRODUCTION (U.S. Tons x 10^3)

Site and Type	Steam Reforming	Partial Oxidation	Electrolysis	Coal Gasification	Liquefaction	Total[a] (Maximum)	Total[a] (Probable)
Bangkok - 200T/D							
Natural gas	157	-	-	-	-	157	157
Oil	152	353	-	-	-	995	568
Coal	-	-	-	-	-	-	-
Electricity (gwh)	78	215	3,564	-	709	-	-
Oil equivalent	18	50	830	-	165	-	-
Johannesburg - 200 T/D							
Natural gas	157	-	-	-	-	157	157
Oil	152	353	-	-	-	353	353
Coal	-	-	-	721	-	1,965	1,090
Electricity (gwh)	78	215	2,564	94	709	-	-
Coal equivalent	36	99	1,639	43	326	-	-
Honolulu - 200 T/D							
Natural gas	157	-	-	-	-	157	157
Oil	152	353	-	-	-	995	568
Coal	-	-	-	-	-	-	-
Electricity (gwh)	78	215	3,564	-	709	-	-
Oil equivalent	18	50	830	-	165	-	-
Beirut - 300 T/D							
Natural gas	232	-	-	-	-	232	232
Oil	223	529	-	-	-	1,490	851
Coal	-	-	-	-	-	-	-
Electricity (gwh)	116	321	5,335	-	1,062	-	-
Oil equivalent	27	75	1,243	-	247	-	-

TABLE 4-1. ANNUAL RAW MATERIAL REQUIREMENTS FOR LIQUID HYDROGEN PRODUCTION (Continued)
(U.S. Tons x 10^3)

Site and Type	Steam Reforming	Partial Oxidation	Electrolysis	Coal Gasification	Liquefaction	Total[a] (Maximum)	Total[a] (Probable)
Sao Paulo - 400 T/D							
Natural gas	314	-	-	-	-	314	314
Oil	298	706	-	-	-	1,990	1,135
Coal	-	-	-	-	-	-	-
Electricity (gwh)	155	429	7,128	-	1,414	-	-
Oil equivalent	36	100	1,661	-	329	-	-
Sydney - 400 T/D							
Natural gas	314	-	-	-	-	314	314
Oil	298	706	-	-	-	706	706
Coal	-	-	-	1,997	-	2,265	2,603
Electricity (gwh)	155	429	7,128	125	1,414	-	-
Coal equivalent	61	169	2,808	49	557	-	-
Tokyo - 500 T/D							
Natural gas	391	-	-	-	-	391	391
Oil	368	880	-	-	-	2,486	1,417
Coal	-	-	-	-	-	-	-
Electricity (gwh)	194	536	8,899	-	1,766	-	-
Oil equivalent	45	125	2,074	-	412	-	-
Los Angeles - 1,300 T/D							
Natural gas	1,017	-	-	-	-	1,017	1,017
Oil	922	2,274	-	-	-	6,453	3,666
Coal	-	-	-	-	-	-	-
Electricity (gwh)	502	1,391	23,112	-	4,585	-	-
Oil equivalent	117	324	5,385	-	1,068	-	-

TABLE 4-1. ANNUAL RAW MATERIAL REQUIREMENTS FOR LIQUID HYDROGEN PRODUCTION (Concluded)
(U.S. Tons x 10^3)

Site and Type	Steam Reforming	Partial Oxidation	Electrolysis	Coal Gasification	Liquefaction	Total[a] (Maximum)	Total[a] (Probable)
Paris - 2,000 T/D							
Natural gas	1,564	-	-	-	-	1,564	1,564
Oil	1,390	2,465	-	-	-	9,929	5,609
Coal	-	-	-	-	-	-	-
Electricity (gwh)	774	2,140	35,554	-	7,060	-	-
Oil equivalent	180	499	8,284	-	1,645	-	-
New York - 2,500 T/D							
Natural gas	1,954	-	-	-	-	1,954	1,954
Oil	1,700	4,308	-	-	-	12,407	6,986
Coal	-	-	-	-	-	-	-
Electricity (gwh)	967	2,674	44,431	-	8,822	-	-
Oil equivalent	225	623	10,352	-	2,055	-	-

[a]Refer to paragraph 4.2.1 for an explanation of these categories.

NOTES:

Fuel requirements for electricity have been computed using 8750 Btu/kwh.

In the event that the Btu content of any of the fuels delivered to the hydrogen plant sites differ from these factors, a correction must be applied.

Natural gas feed stock requirements are based on pure methane. Correction to actual natural gas composition is also necessary.

4.3 RAW MATERIALS AVAILABILITY

Raw materials will be available in the quantities necessary for hydrogen production, as shown in table 4-1, if the area of the proposed hydrogen plant has adequate natural resources or if transportation from other areas can be accomplished with reasonable economy. Of the commodities to be considered, the fossil fuels (oil, gas, and coal) are of prime importance. They may provide not only the process feed stock which yields hydrogen, but may also be the source of energy to generate electricity. Logistically, they demand greater consideration for, if not available locally, they require massive, bulk movement which could represent a significant portion of their ultimate cost.

4.3.1 FOSSIL FUELS

A review of the world's deposits of coal, oil, and natural gas shows that the estimated reserves with the possible exception of natural gas, are far in excess of the quantities required for this hydrogen production program. Gas reserves are not too well defined because demands have not yet stimulated exploration at the newer fields. Major sources of coal are the United States, Western Europe, Australia, and South Africa. A lower-quality coal is abundant in Eastern Europe and China. Major sources of oil are the United States, Venezuela, the Near East (including North Africa), Eastern Europe (primarily Russia), and Indonesia. Gas deposits, usually associated with the oil fields, are best explored in the United States. Substantial deposits are anticipated in other oil fields. Fossil fuel resources, though, are not sufficient to permit local supply at a number of the proposed hydrogen plant locations. The cost effect of importing will be evident at these locations.

4.3.2 NUCLEAR FUELS

Major uranium and thorium deposits already evaluated are in the United States, Canada, Sweden and South Africa. Other deposits of similar or greater magnitude, but not as accurately measured, are located in Asia, Africa, and Australia. Should the generation of electricity from nuclear power become prevalent, the need to process marginal uranium or thorium ores may follow, but over-all resources appear adequate to meet needs for many centuries. Certainly, the hydrogen-fueled aircraft program in the post-1980 period will not make a significant dent in available resources. The lack of uranium resources in the vicinity of proposed hydrogen plants is of little consequence since bulk transport is not a major factor.

4.3.3 WATER POWER

Since production of electricity at hydroelectric stations should result in reduced hydrogen costs at some locations, an evaluation of available water power sources proved beneficial. Although about one-third of the world's electricity is derived from water power, its use as a primary source of electricity for hydrogen plants seems most promising only in Brazil and Thailand. It will, however, also support integrated systems supplying electricity to other hydrogen plant sites, notably in the United States, France, Japan, and Australia.

4.4 PRODUCTION, TRADE, AND CONSUMPTION

Having observed that the commodities required for hydrogen production do exist in sufficient quantity, at least in the form of natural resources, the next step is to determine their availability in terms of the competitive factors of production, consumption, and trade. Analysis of trends during recent years shows that all countries in which hydrogen plants are contemplated use more energy than they produce and, in most cases, imports exceed local production. Energy supplies, particularly using fossil fuels as a source, generally will be available for hydrogen production in a highly competitive environment, with fuels being imported from other areas having an excess.

4.4.1 SOLID FUELS

Study of the export of solid fuels shows primarily all Western European exports consist of interchanges between the Western European countries themselves. Polish and Russian exports remain within the Eastern European bloc. The United States is the world's major exporter of coal (45.4×10^9 metric tons were exported in 1964). Australia and South Africa exported 5×10^9 and 3×10^9 metric tons, respectively, which makes them economically feasible sources insofar as geography permits.

4.4.2 OIL

The world's oil comes from four main areas: The United States, the Caribbean, the Near East (extending into North Africa) and Russia. However, Indonesian fields may become significant. Except for the United States, and to a lesser degree Russia, the oil-rich countries are relatively small consumers; hence, oil is far more available than coal in the world fuel market. The demand for oil as the feed stock or fuel for a large liquid hydrogen producing plant could be readily met from a number of sources, with far less dependency on geography than in the case of coal.

4.4.3 NATURAL GAS

Trade in natural gas is presently almost non-existent, except for a modest amount flowing from Canada to the United States. Future developments being planned include pipelines from Eastern to Western Europe, utilization of North Sea finds in Western Europe and the United Kingdom, and transport of substantial quantities of liquefied natural gas by tanker from fields to markets in Japan, Western Europe, and the United States.

4.4.4 GENERAL

As a final step to understanding of potential cost factors, tables 4-2 and 4-3 show the impact that hydrogen plant requirements have on each country's ability to supply the desired raw materials in light of their own resources or present (1964) trade. The 1964 production, consumption, and trade figures were used because they were the latest available on a comparable basis. For lack of separate data, Hawaii has been included in the United States evaluations although, obviously, supply from the mainland requires separate consideration. In general, resource data does not reflect recent discoveries not yet fully measured. Hence, some countries (Australia and South Africa) show little production of oil and no resources. Since the coal gasification process does not appear attractive other than in Australia and South Africa, table 4-4 has been restricted to these locations.

TABLE 4-2. OIL FOR LIQUID HYDROGEN PLANTS

(All Units in Metric Tons x 10^3)

Location (Country)	Max. Probable Req'ment	Resources	1964 Production	1964 Supply	1964 Imports
Thailand	516	-	10	680	670
South Africa	321	-	10	4,860	4,850
Lebanon	773	-	-	1,310	1,310
Brazil	1,032	48,000	4,350	15,160	10,800
Australia	642	-	190	15,300	15,110
Japan	1,288	3,900	680	63,000	62,320
France	5,099	30,000	3,140	52,420	49,270
U.S. (Honolulu) (Los Angeles) (New York)	516 3,333 6,351	49,500,000	396,330	456,860	60,830
World	19,871	81,600,000	1,436,390	1,434,880	

TABLE 4-3. NATURAL GAS FOR LIQUID HYDROGEN PLANTS

(All Units in Metric Tons x 10^3)

Location (Country)	Max. Probable Req'ment	Resources	1964 Production	1964 Consumption	1964 Imports
Thailand	143	-	-	-	-
South Africa	143	-	-	-	-
Lebanon	211	-	-	-	-
Brazil	285	7,170	390	390	-
Australia	285	a	-	-	-
Japan	355	95,100	1,400	1,400	-
France	1,422	124,300	3,400	3,400	-
U. S. (Honolulu) (Los Angeles) (New York)	143 925 1,776	5,080,000	294,000	299,000	8,400
World	5,688	34,100,000	441,000	438,000	-

[a] Most discoveries have been recent and are still in the process of being measured.

TABLE 4-4. COAL FOR LIQUID HYDROGEN PLANTS

(All Units in Metric Tons x 10^3)

Location (Country)	Max. Probable Req'ment	Resources	1964 Production	1964[a] Consumption
South Africa	991	21,443,000	44,916	43,630
Australia	2,366	1,791,000	27,840 (19,344)[b]	28,960
World	3,357	771,000,000	1,801,110 (439,960)[b]	2,247,470

a - All solid fuels, coal plus lignite plus small amounts of peat and wood in terms of coal equivalent.

b - Lignite

4.5 RAW MATERIAL COSTS

4.5.1 COAL, OIL, AND NATURAL GAS

A summary of the cost of coal, oil, and natural gas at each proposed hydrogen plant is shown in table 4-5. This table is the results from a study of current supply practice at each location, including examination of the present origin of each supply, future possibilities of untapped resources, transportation costs, adjustments in quantity that may be expected in future trade, and recent pricing patterns. The price cited corresponds to the assumed means of supply presented in the "Justification" column. These prices are applied directly in section 5 in determining the cost of hydrogen at each location. Nuclear raw material costs have been included in the nuclear power plant investment and operating costs, based on present costs for fabricated core assemblies and predicted costs of the assemblies in the future.

4.5.2 WATER

Costs for the supply and purification of water have been established on three probable levels. Where fresh water is considered plentiful, a cost of 0.72 cent/ton has been applied for nominal treatment and pumping. Where fresh water must be piped a modest distance, a nominal figure of 1.2 cents/ton has been applied. Where fresh water is scarce, the estimated 1980 Los Angeles cost of 7.2 cents/ton has been applied. More complete analysis of water costs is not warranted since the effect on the hydrogen cost on a per pound basis is negligible.

4.5.3 REFRIGERANTS AND OXYGEN

The raw materials to be used as refrigerants in the hydrogen liquefier are not required in quantities which would contribute significant cost to the end product. The oxygen for the partial oxidation process is supplied by an integral air separation plant, but the oxygen for coal gasification has been considered as supplied from a separate source as a raw material. The cost of oxygen for Johannesburg and Sydney, where the coal gasification process may be economical, is considered to be $5.00 and $4.50 per short ton, respectively, in line with current oxygen prices at plants of comparable size.

4.6 PROJECTED POWER AVAILABILITY

To ensure maximum reliability of electric power supply at minimum cost, the plant providing power to each liquid hydrogen facility should be part of the existing power network or grid. Utilizing past power availability data for each location, reasonable projections for the 1980 to 2000 period can be made. The incorporation of hydrogen plant power requirements in this projected network can then be made to optimize power plant size. Table 4-6 is a summary of projected electric power availability in 1980 and 2000 for each of the suggested locations.

TABLE 4-5. COSTS OF RAW MATERIALS AT USE-POINT

Plant Location	$ Cost Per U.S. Ton	Type	Justification
		Coal	
Honolulu (access to sea)	15.00	Aust. bit., 11,100 Btu/lb	Referenced to actual cost in Japan
Bangkok (access to sea)	12.50	Aust. bit., 11,100 Btu/lb	Referenced to actual cost in Japan
Johannesburg	1.80 – 2.40 –	S. Afr. bit. at minemouth; at Johannesburg, 9500 Btu/lb	Government controlled mine price of $1.76/ton + handling and freight for 100-mile average
Beirut	15.00	Polish or Russian	Little basis for price since no trade exists (assume higher than Western Europe)
Sao Paulo	14.00	U.S. bit., 13,300 Btu/lb	$8.50 per ton from Norfolk + $5.50 freight (no duty included)
Sydney (access to sea)	2.30 – 3.00 –	Aust. black, at minemouth; at Sydney, 11,100 Btu/lb	Anticipated minemouth price at Lidell power plant + handling and freight to Sydney
Tokyo (access to sea)	13.42	Aust. black, 11,100 Btu/lb	Average price, Tokyo (quantity purchase to offset duty and handling)
Los Angeles	9.85[a]	Colo. lignite, 10,000 Btu/lb	$4.50/ton loaded in Colo. + $5.35/ton freight
Paris	13.36	U.S. bit., 13,300 Btu/lb	$11.36/ton for steaming coal, cif Atlantic port (allow $2.00 for freight and customs)
New York (access to sea)	7.92	U.S. bit., 13,300 Btu/lb	Best actual annual average price at New York power plant

[a] Burning of coal is probably not legal in Los Angeles County.

TABLE 4-5. COSTS OF RAW MATERIALS AT USE-POINT (Continued)

Plant Location	Per Bbl.	Type	Justification
		Oil	
Honolulu (access to sea)	2.25	155,200 Btu/gal	Average actual cost at plant per FPC Report (no additional quantity discounts assumed)
Bangkok (access to sea)	2.15	Middle East crude or heavy fuel from Indonesia	Posted price f.o.b. port of origin and freight (quantity discount to offset duty and port fees)
Johannesburg	2.25[b]	Middle East or Nigerian crude	(Same as above)
Beirut	1.74	No. 6 from Sidon, 19° API	From pipeline at Sidon at 1.65 + 0.09 freight (assumes no additional duties)
Sao Paulo	2.11[c]	Crude from Curacao or Venezuela, 15° API	Posted price + freight to Santos + pipe to Sao Paulo (quantity discount to offset nominal duty)
Sydney (access to sea)	2.12	Crude from Middle East or Indonesia, 35° API	F.o.b. port side average price (quantity discount to offset handling charges, no duty in Australia)
Tokyo (access to sea)	2.27	Heavy or medium fuel from Indonesia, 18° API	Posted price + freight (quantity discount to offset duty and port fees)
Los Angeles	1.88	152,500 Btu/gal	Best actual price on annual basis per MM btu to power plant in L.A. County
Paris	2.39	Libyan crude, 37° API	F.o.b. Dunkerque or LeHavre at $2.39 (quantity discount to offset duty and piping cost to Paris)
New York (access to sea)	1.85	148,900 Btu/gal	Best actual price on annual basis by New York power plant

[b] High duty to protect coal interest may cause increase.

[c] High duty to protect government-owned oil industry may cause increase.

TABLE 4-5. COSTS OF RAW MATERIALS AT USE-POINT (Concluded)

Plant Location	$ Cost Per MCF	Type	Justification
Natural Gas			
Honolulu (access to sea)	0.45	Alaskan LNG, 1000 Btu/scf	No commercial basis (assumes price in Hawaii to be comparable to Japan price without duty)
Bangkok (access to sea)	0.45	LNG from Indonesia, 1000 Btu/scf	No commercial basis (assumes liquefaction in Indonesia and tanker transport)
Johannesburg	0.45	LNG from Middle East or North Africa, 1000 Btu/scf	No commercial basis (assumes liquefaction at source + tanker transport)
Beirut	0.35	Piped from Arabia or Iraq, 1000 Btu/scf	No commercial basis (assumes pipeline from source about 400 miles)
Sao Paulo	0.40	Piped from Bolivian fields, 1000 Btu/scf	No commercial basis (assumes pipeline from source about 700 miles)
Sydney (access to sea)	0.35[d]	Gippsland or other Australian fields, 1000 Btu/scf	Reflects anticipated well price of 29 cents + piping to Sydney
Tokyo (access to sea)	0.368	LNG from Sakhalin Island, 1000 Btu/scf	Reflects current Russo-Japanese negotiations
Los Angeles (access to pipelines)	0.338	Pipeline gas, 1077 Btu/scf	Best actual price per MM Btu on annual basis by power plant in L.A. County
Paris	0.48	LNG from Algeria, 1000 Btu/scf	40.9 cents, Medit port + pipeline cost to Paris (some mixture with 43.6-cent domestic gas)
New York (access to sea)	0.363	Pipeline gas, 1045 Btu/scf	Best actual price per MM Btu on annual basis at New York power plant

[d] No positive evidence that there is adequate supply.

TABLE 4-6. PROJECTED GRID CAPACITIES AND PROPOSED PLANT DESCRIPTIONS

Location (City)	Mw Grid Capacity 1980	Mw Grid Capacity 2000	LH_2 Load Mw	Process Type	Power Plant Size, Mw	Description (Type)	Assumed Plant Location
Bangkok	2,800	24,000	97	Steam reforming	600	Hydro	350 miles north at Pa Mong Dam
			113	Partial oxidation	600	Hydro	
			530	Electrolysis	1,500	Hydro	
Honolulu	1,000	1,800	97	Steam reforming	150	Oil	Power plant at air terminal
			113	Partial oxidation	150	Oil	
			530	Electrolysis	600	FBR	
Johannesburg	7,200	15,000	87	Coal gasification	1,100	Coal	50 to 100 miles from air terminal
			97	Steam reforming	1,100	Coal	
			113	Partial oxidation	1,100	Coal	
Beirut	1,600	10,400	145	Steam reforming	300	Oil	Power plant at air terminal
			171	Partial oxidation	300	Oil	
			990	Electrolysis	600	Oil	
Sao Paulo	17,600	56,000	193	Steam reforming	1,100	Hydro	175 miles to Furnase Dam at site
			226	Partial oxidation	1,100	Hydro	
			1,050	Electrolysis	2,000	FBR	
Sydney	8,400	24,000	193	Steam reforming	1,100	Coal	50 to 100 miles from air terminal at site
			226	Partial oxidation	1,100	Coal	
			1,050	Electrolysis	2,000	FBR	
Tokyo	39,000	168,000	232	Steam reforming	1,100	FBR	Plants at air terminal
			272	Partial oxidation	1,100	FBR	
			1,300	Electrolysis	2,000	FBR	
Los Angeles	60,000	120,000	625	Steam reforming	2,000	FBR	Plants at air terminal
			735	Partial oxidation	2,000	FBR	
			3,400	Electrolysis	3,000	FBR	
Paris	20,800	48,000	965	Steam reforming	2,000	FBR	Plants at air terminal
			1,135	Partial oxidation	2,000	FBR	
			5,220	Electrolysis	3,000	FBR	
New York	60,000	120,000	1,220	Steam reforming	2,000	FBR	Plants at air terminal
			1,430	Partial oxidation	2,000	FBR	
			6,600	Electrolysis	3,000	FBR	

4.7 METHODS OF POWER GENERATION

Various methods of electric power generation should be available to supply the projected 1980 power requirements. Hydroelectric (including pumped storage), conventional steam plants (using coal, oil, or gas), and nuclear plants (either conventional or breeder types) can be incorporated in the power networks. Other concepts, such as magneto hydrodynamics (MHD), coal gasification, fuel cells, solar energy, and nuclear fusion, do not appear to be sufficiently advanced for large-scale utilization in the 1980-1985 period.

4.8 SELECTION OF POWER PLANT SIZE

Based on economic factors, it is advantageous to utilize the largest practical power plant at each hydrogen-producing site. For fossil fuels, an 1100 mw unit has been selected. The maximum size of nuclear units is estimated at 3000 mw. Another limitation in selection of power plant size is reliability of power supply. To ensure continuous service, a system must have sufficient reserve capacity to supply power when the largest generating unit is out of service. This normally limits the size of individual power plants to about 15 or 20 percent of the system's peak load. Using projected power requirements from the applicable table in Appendix B of the Final Report and the above limitations, the optimum power plant sizes have been determined as listed in table 4-6.

4.9 DETERMINATION OF POWER PLANT INVESTMENT

Power plant investment is dependent on plant size, design, and location. The effect of plant size on investment is shown in section 4 of the Final Report. Design is influenced by plant location, utilization, efficiency, and fuel cost. A power plant designed for high efficiency will require operating conditions which increase the cost of machinery and associated equipment. The resultant savings in fuel cost, therefore, must be evaluated against higher capital costs to determine optimum design characteristics. Plant construction, labor, and material costs will be dependent upon location. The expected power plant utilization factor will be dependent on the function of the plant for either base load or peaking service and will also have a direct effect on plant design.

Further study of cost factors determined power plant investment in dollars per kilowatt of installed capacity versus size. The design criteria for the fossil fuel plants was based on supercritical boilers with reheat cycles, using comprehensive investment data. Nuclear plant investment data are based on information from various sources. Hydro plant investment data are derived from actual installed costs. All data have been based on ideal construction conditions, using the Washington, D.C. area as the construction base. Area adjustment factors for each specific location must be applied to these investment costs. These factors have been determined for the various areas by the Department of Defense from actual bid experience and have been adjusted relative to a base index of 1.0 for Washington, D.C.

4.10 DETERMINATION OF POWER COST

Many variables will affect the busbar cost of electric power from a new plant. They include plant size, investment, fixed charge rate on the investment, fuel cost, operation and maintenance costs, load factor, and plant availability.

The following assumptions have been made in order to estimate the busbar cost of power. Plant size and investment were determined by using the analysis developed in paragraphs 4.8 and 4.9. Each area electric grid system was assumed to supply electricity to the liquid hydrogen facility continually at 2300 volts at the busbar (or substation in the case of transmitted power). Calculations were for a 30-year contract period.

4.10.1 LOAD FACTOR

The cost of power, which includes the cost of reserve power, was based on an average production of 0.96 kwh/hr/kw of capacity from the optimum size plant for a 30-year period.

4.10.2 PLANT AVAILABILITY

The optimum size plant is estimated to have 85 percent availability, with reserve power available during the remainder of the year.

4.10.3 FIXED-CHARGE RATE

The annual fixed charge rate on the investment has been based on using an annual rate of return on capital investment of 6½ percent per year. This amounts to 4.15 percent levelized rate of return over a 30-year life for fossil and nuclear power plants. The income tax effect has been computed based on United States rates, using a capital structure of 50 percent equity financing, accelerated depreciation, and investment tax credits. Straight line depreciation, ad valorem taxes at 2.0 percent per year, and insurance at 0.15 percent for fossil and 0.40 percent for nuclear plants have also been used. Table 4-7 is a tabulation of this analysis and has been used as the standard in this study.

TABLE 4-7. FIXED-CHARGE RATE STANDARDS

Item	Fossil(%)	Nuclear (%)	Hydro (%)
Levelized return on investment	4.15	4.15	4.15
Depreciation	3.35	3.35	2.00
Income-tax effect	1.35	1.35	1.25
Insurance	0.15	0.40	0.10
Property taxes	2.00	2.00	1.00
Total	11.00	11.25	8.50

Variations in fixed charge rates will obviously occur at the different locations. Table 4-8 is an example of some typical reported, but unconfirmed, fixed-charge rates.

TABLE 4-8. EXAMPLES OF FIXED-CHARGE RATES

Location	Area Adjust. Factor	%/Fixed-Charge Rate, Nuclear	%/Fixed-Charge Rate, Fossil
France	1.1	9.4	8.06
New York City	1.3	12.55	12.05
Montreal	.9	7.00	7.00
United Kingdom	1.0	10.00	10.00
Tokyo	.8	14.00	13.00
Los Angeles	1.1	13.00	12.50
Hawaii	1.3	11.30	10.80
TVA	1.0	5.90	5.90

4.10.4 OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs for each plant type have been determined from available data, based on analysis of estimated plant complexity.

4.10.5 COST OF FUEL

The cost of fuels presented in table B-12 of the Final Report is the assumed cost delivered to the air terminal. Storage for oil or coal at the site is included in the power plant investment. Nuclear fuel costs are based on available data. The fuel costs per kwh generated for each plant size and method have been computed by using 8750 Btu/kwh for coal, oil, and gas, and 10,500 Btu/kwh for nuclear fuel.

4.10.6 RESERVE

A 15 percent reserve is required for each proposed power plant. The investment for this reserve is considered to be comparable in $/kw to the proposed power plant investment. Therefore, the formula for determination of power cost must include the investment cost of reserve. Additional operating and maintenance costs at 15 percent have been used for allocating the costs of maintaining reserves.

Based on the foregoing methodology and analysis, power costs were determined for various size and type plants at each location. A summary of the optimum power costs anticipated at each site is presented in table 4-9.

TABLE 4-9. UNIT COSTS OF ENERGY BASED ON INTEGRATED SYSTEM DESIGN AT EACH LOCATION

Site	Load Mw	Plant Size Mw	Fuel	Plant Type	Plant Cost $/kw	Mills per kwh				
						Fixed Charge	Fuel Cost	Operating	Transmission	Total
Hydrocarbon Processes										
Bangkok	113	600	-	Hydroelectric	273	2.76	-	0.35	0.50	3.61
Honolulu	113	150	Oil	Steam	177	2.32	3.02	0.72	-	6.06
Johannesburg	113	1,100	Coal	Steam	111	1.45	0.96	0.26	0.13	2.80
Beirut	171	300	Oil	Steam	127	1.66	2.45	0.58	-	4.69
Sao Paulo	226	1,100	-	Hydroelectric	252	2.55	-	0.22	0.23	3.00
Sydney	226	1,100	Coal	Steam	117	1.53	1.18	0.26	0.15	3.12
Tokyo	272	1,100	Nuclear	Fast-breeder	168	2.25	0.60	0.22	-	3.07
Los Angeles	735	2,000	Nuclear	Fast-breeder	135	1.80	0.60	0.15	-	2.55
Paris	1,135	2,000	Nuclear	Fast-breeder	130	1.74	0.60	0.15	-	2.49
New York	1,430	2,000	Nuclear	Fast-breeder	160	2.13	0.60	0.15	-	2.88

TABLE 4-9. UNIT COSTS OF ENERGY BASED ON INTEGRATED SYSTEM DESIGN AT EACH LOCATION (Concluded)

Site	Load Mw	Plant Size Mw	Fuel	Plant Type	Plant Cost $/kw	Mills per kwh				
						Fixed Charge	Fuel Cost	Operating	Transmission	Total
Electrolysis Process										
Bangkok	530	1,500	-	Hydroelectric	268	2.71	-	0.17	0.35	3.23
Honolulu	530	600	Nuclear	Fast-breeder	266	3.57	0.80	0.35	-	4.72
Johannesburg	530	1,100	Coal	Steam	111	1.45	0.96	0.26	0.09	2.76
Beirut	990	600	Oil	Steam	109	1.43	2.45	0.38	-	4.26
Sao Paulo	1,050	2,000	Nuclear	Fast-breeder	154	2.06	0.60	0.15	-	2.81
Sydney	1,050	2,000	Nuclear	Fast-breeder	130	1.74	0.60	0.15	-	2.49
Tokyo	1,300	2,000	Nuclear	Fast-breeder	111	1.48	0.60	0.15	-	2.23
Los Angeles	3,400	3,000	Nuclear	Fast-breeder	127	1.70	0.60	0.11	-	2.41
Paris	5,220	3,000	Nuclear	Fast-breeder	121	1.62	0.60	0.11	-	2.33
New York	6,600	3,000	Nuclear	Fast-breeder	150	2.01	0.60	0.11	-	2.72

Section 5

COMPOSITE SYSTEM ANALYSES

Information presented herein summarizes the results of the evaluations. Plants considered for a given location are characterized by the production and gas purification process employed. Data presented for the respective location is keyed to the gas process equipment considered.

5.1 GUIDELINE EVALUATIONS

The cost studies completed are based upon the requirements for liquid hydrogen plants at 10 geographic locations. Initial considerations were directed toward "stand alone" plants; that is, plants disassociated from other local industrial activity. Subsequent to the "stand alone" evaluations, qualitative considerations are given to the "integrated" plant concept at the respective locations. To simplify these initial analyses, the following guidelines were established:

(1) All liquid hydrogen plants were considered to be adjacent to product use points.

(2) Net production for the plants was calculated to be the nominal amounts delivered to the aircraft manifolds. The New York plant, for example, will have a net production of 2500 T/D.

(3) Geographic economic considerations are not incorporated in these analyses. These considerations, e.i., air pollution, taxes, etc., are left for future more detailed analyses.

(4) Material and energy supply was calculated to be at the liquid hydrogen plant.

(5) The liquid hydrogen plants are to be designed to provide 100 percent production at all times except for catastrophic occurrences.

(6) Capital investment was adjusted for the respective geographic locations.

(7) Capital investment fixed charge rate was taken as 11 percent/yr.

5.2 BANGKOK - 200 T/D

Steam reforming or partial oxidation based plants are competitive with each other in terms of unit product cost. Coal gasification or electrolysis based plants are not projected to be competitive with either of the other two plants. Future raw material and energy supply could support either of the competitive plants. Valuation of byproducts from the partial oxidation based plant could amount to a unit credit of 0.3 cent/lb LH_2.

The Bangkok industrial community is forecast to include petroleum processing in the future. It could be projected that a partial oxidation plant would utilize refinery off-gases. These off-gases may contain from 90 to 95 percent hydrogen by volume. Considering an integrated facility utilizing refinery off-gases, and assuming other credits resultant from such a plan, it is postulated that the unit product cost as shown in table 5-1 could be reduced to 9.3 cents/lb LH_2 for Bangkok.

TABLE 5-1. SUMMARY PRODUCTION COST DATA (BANGKOK)

Component of Cost	Annual Production Cost in Millions of USA Dollars			
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Coal Gasification Based Plant	Electrolysis Based Plant
Raw Materials	5.52	4.51	14.06	0.23
Energy	2.84	3.34	2.90	13.85
Capital Investment	5.75	5.85	7.37	8.33
Operating Cost	3.11	3.29	4.72	4.95
Total	17.22	16.99	29.05	~~26.86~~ 27.36
	Unit Product Cost			
	11.8 cents/lb LH_2	11.6 cents/lb LH_2	19.8 cents/lb LH_2	~~18.4~~ 18.7 cents/lb LH_2

5.3 HONOLULU - 200 T/D

Steam reforming or partial oxidation based plants are competitive with each other and display little projected unit product cost difference. Electrolysis based plants are not projected as being economically competitive. The ability to obtain revenue from byproduct marketing is doubtful. It is projected that the unit product cost of 13.2 cents/lb LH_2 is representative.

The industrial community in Honolulu is at present limited. No basis is seen at this time for projecting a large or complex industrial development in the future. As a result, it is not expected that an integrated plant concept could be incorporated at the Honolulu location. A single notable exception to this projection does exist in that water desalinization may become a large industry. Considering presumed lower cost process energy for this situation, the unit product cost reduction as shown in table 5-2 may be 12.4 cents/lb LH_2.

TABLE 5-2. SUMMARY PRODUCTION COST DATA (HONOLULU)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	5.95	4.99	0.47
Energy	4.77	5.60	20.25
Capital Investment	5.49	5.59	7.96
Operating Cost	3.11	3.29	4.45
Total	19.32	19.47	33.13
	Unit Product Cost		
	13.2 cents/lb LH_2	13.3 cents/lb LH_2	22.7 cents/lb LH_2

5.4 JOHANNESBURG - 200 T/D

The hydrocarbon and coal gasification based plants are considered competitive. The electrolysis based plant is projected to have a unit product cost approximately 50% higher than the other plants. This eliminates the electrolysis based plant from further consideration. Future government commodity pricing of South African coal resources is expected to be such that the coal based plant will be more competitive with the hydrocarbon based plants. Under these conditions, it is expected that the Johannesburg plant will be based upon coal gasification and have a unit product cost of 10.8 cents/ lb LH_2. Byproduct from the coal gasification based system is primarily carbon dioxide which is considered of no value in this study.

Prospects for an integrated plant are considered good in Johannesburg. A large diversified industrial community is projected. Industrial conditions such as these would likely result in the oxygen for the coal process being supplied as an incremental product from an industrial gas plant. Considering this, the cost of oxygen could be $3.50/T as opposed to $5.00/T used in the calculations. This consideration alone, as shown in table 5-3, would result in a price reduction from 10.8 cents/lb LH_2 to 10.4 cents/ lb LH_2. Other considerations could be made, but it is not expected that a total unit product cost reduction would exceed 10.8 cents/lb LH_2

TABLE 5-3. SUMMARY PRODUCTION COST DATA (JOHANNESBURG)

Component of Cost	Annual Production Cost in Millions of USA Dollars			
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Coal Gasification Based Plant	Electrolysis Based Plant
Raw Materials	5.64	4.74	5.06	0.25
Energy	2.21	2.59	2.26	11.84
Capital Investment	5.10	5.19	6.55	7.40
Operating Cost	3.11	3.29	4.72	4.45
Total	16.06	15.81	18.59	23.94
	Unit Product Cost			
	11.0 cents/lb LH_2	10.8 cents/lb LH_2	12.7 cents/lb LH_2	16.4 cents/lb LH_2

5.5 BEIRUT - 300 T/D

The hydrocarbon based plants are competitive at the Beirut location. Coal processing has not been evaluated since coal is not considered a feasible raw material for this location. The electrolysis-based plant is projected to result in a unit product cost 85 percent greater than the hydrocarbon-based plants. Marketability of byproduct at the Beirut location is judged comparable to that postulated for Bangkok. Applying a corresponding approximate 3 percent byproduct credit, a reduction in unit product cost from 10.9 cents/lb LH_2 to 10.6 cents/lb LH_2 is projected.

An integrated plant will be possible in Beirut. Analogous to the Bangkok analysis, a unit product cost reduction of 20 percent would be the maximum anticipated for a well developed integrated industrial complex. This would result in a unit product cost reduction as shown in table 5-4 from 10.9 cents/lb LH_2 to 8.7 cents/lb LH_2.

TABLE 5-4. SUMMARY PRODUCTION COST DATA (BEIRUT)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	7.08	5.86	0.69
Energy	5.56	6.53	27.46
Capital Investment	7.05	7.18	10.58
Operating Cost	4.12	4.36	5.92
Total	23.81	23.93	44.65
	Unit Product Cost		
	10.9 cents/lb LH_2	10.9 cents/lb LH_2	20.4 cents/lb LH_2

5.6 SAO PAULO - 400 T/D

All of the plants evaluated must be considered competitive. The optimum choice for Sao Paulo is not clearly evident. Oil supply to the site could be difficult. It is likely that natural gas supply from Bolivian or Venezuelan fields will be developed in preference to an oil supply system. The present oil supply system is sufficient to support fueling of a steam reforming plant processing natural gas. An electrolysis based plant could be considered if energy costs were reduced. This would result in development of larger regional electrical requirements. No significant credit can be given for the byproduct marketability of the steam reforming based plant; thus, the stand alone unit product cost as shown in table 5-5 of 10.4 cents/lb LH_2 is projected.

TABLE 5-5. SUMMARY PRODUCTION COST DATA (SAO PAULO)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	10.27	9.21	0.45
Energy	4.73	5.55	24.06
Capital Investment	10.42	10.60	15.92
Operating Cost	5.00	5.30	7.23
Total	30.42	30.66	47.66
	Unit Product Cost		
	10.4 cents/lb LH_2	10.5 cents/lb LH_2	16.3 cents/lb LH_2

The industrial community may develop to support an agricultural economy. It is feasible that an integrated plant could be developed in such a situation. A reduction in the cost of raw materials and process energy could be expected in relation to the hydrogen plant. A natural gas cost reduction from \$0.40/MCF to \$0.30/MCF might be expected, as well as lowering energy cost to \$0.00281/kwh. These changes in unit product costs would result in reduction of the unit product cost from 10.4 cents/lb LH_2 to 9.8 cents/lb LH_2. Further reductions in unit product cost certainly could be expected, but escape evaluation at this point in time. It is not unlikely that a unit product cost of 9.5 cents/lb LH_2 could be reached in such an expanded industrial community.

5.7 SYDNEY - 400 T/D

For practical purposes the hydrocarbon and coal based plants can be considered comparable to each other. The electrolysis based plant is not projected to be economically competitive. Economic considerations could result in a product from the coal based plant being manufactured at the cost for the steam reforming based plant. It is projected that unit product cost as shown in table 5-6 would be 9.8 cents/lb LH_2, presumably from a coal gasification based plant.

TABLE 5-6. SUMMARY PRODUCTION COST DATA (SIDNEY)

Component of Cost	Annual Production Cost in Millions of USA Dollars			
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Coal Gasification Based Plant	Electrolysis Based Plant
Raw Materials	9.93	10.48	9.56	0.49
Energy	4.91	5.77	5.02	21.33
Capital Investment	8.75	8.90	11.21	13.37
Operating Cost	5.00	5.30	7.41	7.23
Total	28.59	30.45	33.20	42.42
	Unit Product Cost			
	9.8 cents/lb LH_2	10.4 cents/lb LH_2	11.4 cents/lb LH_2	14.5 cents/lb LH_2

Projections are presently prepared for a well developed industrial community in the post-1980 period. The prospect of utilizing the integrated plant concept at this location does exist. The exact nature of the future integrated plant is not understood. A lower cost energy and a measure of byproduct credit would be anticipated. It is reasonable to expect that unit product cost reduction from 10 to 15 percent would result from such a development. Considering a maximum unit product cost credit of 15 percent, the projected unit product cost from an integrated plant is 8.3 cents/lb LH_2.

5.8 TOKYO - 500 T/D

Initial evaluation indicates a hydrocarbon based plant at the Tokyo location. Natural gas supply currently is not sufficient to support a large scale hydrogen production plant. However, future activity in the natural gas supply is expected to be suitable enough for a steam reforming based plant. It should be noted that an electrolysis based plant can be projected as a remote possibility. The presently evaluated 40 percent higher unit production cost may be reduced based on future economic considerations. If credit for the byproduct electrolytic oxygen could be established at $4.00/T, a reduced unit production cost of 12.0 cents/lb LH_2 could be anticipated. It is apparent that future studies should consider the electrolysis based plant although it is not now projected as being competitive.

Special details related to future integrated plants are not made herein. Undoubtedly, such plants could be employed. Anticipating this, unit product cost reductions ranging from 10 to 15 percent would be expected. Considering as shown in table 5-7, unit product cost of 9.9 cents/lb LH_2 as the basis, an integrated plant unit production cost of 8.4 cents/lb LH_2 is expected.

TABLE 5-7. SUMMARY PRODUCTION COST DATA (TOKYO)

Component of Cost	Annual Production Cost in Millions of USA Dollars			
	Steam Reforming Based Plant	Partial Oxidation Based Plants	Coal Gasification Based Plants	Electrolysis Based Plants
Raw Materials	13.49	13.23	37.70	1.17
Energy	6.06	7.11	6.19	23.93
Capital Investment	10.05	10.23	12.87	15.84
Operating Cost	6.51	6.95	9.59	9.53
Total	36.11	37.52	66.35	50.47
	Unit Product Cost			
	9.9 cents/lb LH_2	10.3 cents/lb LH_2	18.2 cents/lb LH_2	13.8 cents/lb LH_2

5.9 LOS ANGELES - 1300 T/D

The hydrocarbon based plant will be developed for the Los Angeles location. No clear preference with respect to type exists at this time. Future raw material supply appears adequate to support either hydrocarbon plant. Byproduct credits, if applicable, may establish preference for one of the system types. Based on considerations for byproduct credits at other locations, it may be expected that the unit production cost as shown in table 5-8 of 8.4 cents/lb LH_2 could be reduced to 8.1 cents/lb LH_2.

TABLE 5-8. SUMMARY PRODUCTION COST DATA (LOS ANGELES)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	30.67	28.14	3.01
Energy	13.05	15.33	67.13
Capital Investment	23.03	23.41	38.54
Operating Cost	11.68	12.42	17.23
Total	78.43	79.30	125.91
	Unit Product Cost		
	8.3 cents/lb LH_2	8.4 cents/lb LH_2	13.3 cents/lb LH_2

An integrated plant concept is directly applicable to the Los Angeles location. For example, a complete integrated industrial complex, including power generation, water processing, etc., could be erected on a man-made island. It would fully be expected that unit production costs could be reduced from 10 to 15 percent. Considering a 15 percent reduction, the unit production cost would be 7.1 cents/lb LH_2.

5.10 PARIS - 2000 T/D

Initial evaluations indicate that the steam reforming based plant would be developed for the Paris location. Future raw material supply for this plant is expected to be adequate while supply of petroleum products for partial oxidation will be less complete.

Little revenue can be projected for byproduct marketing. The hydrogen plant will be a large installation relative to other surrounding industrial activities. The ability for surrounding industry to profitably use the amounts of byproduct produced is questionable. For this reason, no byproduct credits are projected.

The integrated plant concept is applicable to the Paris location. However, overall future industrial development in this area will be somewhat restricted by the present high level of industrial development. Possible unit product cost reductions for this area resultant from the integrated concept may range from 5 to 10 percent. Considering the 10 percent cost reduction as shown in table 5-9, the unit product cost would be 7.7 cents/lb LH_2.

TABLE 5-9. SUMMARY PRODUCTION COST DATA (PARIS)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	60.58	58.49	2.32
Energy	19.60	23.01	99.78
Capital Investment	29.43	29.90	49.98
Operating Cost	15.18	16.15	22.38
Total	124.79	127.55	174.46
	Unit Product Cost		
	8.5 cents/lb LH_2	8.7 cents/lb LH_2	11.9 cents/lb LH_2

5.11 NEW YORK - 2500 T/D

The hydrocarbon based plants are competitive at the New York location. Studies of raw material indicate, however, that supply of natural gas to this area may not be adequate to support the hydrogen plant. As an alternative, an oil supply could be developed adequately. Certain price adjustments would result from preferential site location. That is, oil prices in the New York area are sensitive to off-loading location. A credit for byproduct steam has been estimated as 0.2 cent/lb LH_2. Other byproduct credits are considered negligible. This would yield a unit product cost of 7.9 cents/lb LH_2.

Plants could be developed in the New York area similar to Los Angeles. Exceptions for unit product cost reduction as shown in table 5-10 range from 5 to 10 percent. Calculating the maximum reduction, unit product cost from the integrated plant would be 7.3 cents/lb LH_2.

TABLE 5-10. SUMMARY PRODUCTION COST DATA (NEW YORK)

Component of Cost	Annual Production Cost in Millions of USA Dollars		
	Steam Reforming Based Plant	Partial Oxidation Based Plant	Electrolysis Based Plant
Raw Materials	60.62	54.46	5.82
Energy	28.33	33.27	145.57
Capital Investment	41.56	42.25	74.01
Operating Cost	17.35	18.52	26.08
Total	147.86	148.50	251.48
	Unit Product Cost		
	8.1 cents/lb LH_2	8.1 cents/lb LH_2	13.8 cents/lb LH_2

Section 6

SYNOPSIS

The previous sections of this study represent the cost for the various plant locations. Concluding comments and observations related to this study are presented in the following paragraphs.

6.1 DATA ACCURACY

A relative appreciation or ranking of plant designs has been accomplished. More specific cost determinations and calculations for final production cost accuracy would have to be completed in future comprehensive studies. Qualitatively, the cost data accuracy range is 20 percent of the values determined. Many inputs in the data development of this study are accurate within a range of + 10 percent, while others are obviously more speculative. A detailed evaluation of calculation accuracy is not justified at this point. The uncertanties related to some specific system characteristics result in unfavorable economics. (Especially, advanced systems such as water electrolysis, hydrogen halide, and coal gasification.) Raw material and energy requirements for the systems considered reflect high process efficiency, approaching stoichiometric limits perhaps, while operating cost and investment data are more speculative. Development work in the future will then reduce the uncertainties. Reduction of the uncertainties should tend to make certain systems more competitive, since a conservative approach was taken in the situations of speculative analysis.

6.2 FUTURE PRODUCTION COSTS

The product costs determined and presented in this study are significant in relation to future large scale production of liquid hydrogen and its use. Future cost structures undoubtedly will differ somewhat from the projections presented in this report. The following paragraphs relate to some of the general future production costs.

Fixed charges based upon the plant investment typically constitute 30 to 32 percent of the production cost for hydrocarbon based and electrolysis based plants. Annual fixed charge calculations in this study were based on 11 percent of the original plant investment. The 11 percent value developed does not reflect what may in fact be future applicable rates. Financing, tax considerations, etc., could yield capital charge rates ranging from 5 to 15 percent. The effect upon the unit product cost is apparent. For example, unit product cost for New York City (partial oxidation based plant) ranges from 6.9 to 8.9 cents/lb LH_2, corresponding to annual capital charge rates ranging from 5 to 15 percent.

In addition to variation in capital charge rates, future plant investments will likely be somewhat different from those presented in this study. A base set of geographic adjustment factors was incorporated in the calculations for this study. Future developments could alter significantly the adjustment factors. Also, as noted, capital investment projections for the various plants could be in error.

Preceding page blank

The basic unit product cost of raw material and energy requirements are well defined at the present time and will undergo relatively minor change in the future. Approaches to stoichiometric limits and ideal cycle efficiencies restrict further large improvements. Future reduction of unit product cost for the liquid hydrogen due to raw material and energy will be dependent upon the unit costs for these commodities. For the hydrocarbon and electrolysis-based plants, raw material and energy costs typically represent from 55 to 60 percent of the unit product cost. Future commodity costs would not be lowered by more than 10 to 15 percent. In many cases, respective commodity costs could in fact be greater than projected. Assuming a 10 percent decrease in unit commodity costs, the product cost for New York City (partial oxidation based plant) would be 7.7 cents/lb LH_2 reduced from 8.1 cents/lb LH_2. Likely cost reduction in capital investment charges appears to be more promising with respect to decreasing product costs.

Operating costs are the smallest component of unit product cost, typically being 8 to 13 percent of the unit product cost for hydrocarbon based and electrolysis based plants. Large changes in future analyses of the operating costs would be required to significantly affect unit product cost. Referring again to New York City (partial oxidation based plant), reduction of operating costs by 20 percent would result in a reduction of unit product cost to 7.9 cents/lb LH_2 from 8.1 cents/lb LH_2.

In addition to the cost reduction information stated, consideration of future integrated facilities could result in cost reduction beyond the 10 to 20 percent used in this study. No fixed understanding of effect can be developed without a specific detailed study. Air Products currently is operating an integrated cryogenic-chemical facility. It has been judged that facility integration resulted in a 15 percent lower unit product cost for liquid hydrogen, compared to the "stand alone" plant.

Future large scale liquid production could involve plant bases significantly different from those used in this study. It could, for example, prove to be advantageous to have fewer production points and transport the product to use points. An example of this would be producing liquid hydrogen in the Venezuelan gas fields and transporting it to New York, Sao Paulo, etc., by massive transoceanic shipping. Natural gas fields in Alaska and other raw material concentration points could be similarly developed.

6.3 FUTURE TECHNOLOGY

Future technological development will be directed toward capital investment reduction in respective systems. Product cost is very sensitive to capital value of systems comprising a given plant. Development of advanced construction material, for example, will hopefully lead to lower cost cells employed in electrolysis processes.

The various process characteristics will also receive attention, but further optimization will be in the nature of incremental steps as opposed to a sweeping revision. Machinery efficiencies, for example, may be improved from 70 to 80 percent through future developmental work. Of more significance, however, would be the cost reduction of the capital goods in the process using the more efficient machine.

It is expected that much effort will be expended to develop coal as a raw material for hydrogen production. Another fertile area for process development is that of several products, including gaseous

hydrogen, being issued from integrated process plants. As an example, generation of synthesis gas (nitrogen and hydrogen) is used for production of fertilizer. Presumably "sharing of costs" would reduce the burden allocated to the gaseous hydrogen production. Development work relating to fertilizer, incorporating nuclear energy and water processing, has been undertaken within the past two years. With this understanding, in future years, certain entirely new processes may appear.